REVIEW MEMORANDUM - DRAFT PERMIT
Regulation No. 30 (TITLE V) DRAFT OPERATING PERMIT
The Premcor Refining Group, Inc.

2000 Wrangle Hill Road
Delaware City, Delaware 19706
PERMIT: AQM-003/00016 - Part 2 Draft

MEMORANDUM SETUP:

This memorandum constitutes Part 2 of the technical and regulatory review of an application submitted by The Premcor Refining Group, Inc. (Premcor) for a Regulation No. 30 (Title V) permit. It's purpose is to describe the emission units and applicable requirements in support of the attached draft Title V Operating Permit (Part 2) for the above facility. The memorandum is setup in the following format:

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The applicable requirements as they pertain, based upon a technical and regulatory review, to the emission units and insignificant activities identified by the Company are discussed in the remainder of this memorandum. The regulatory review will indicate those applicable requirements that are "state only enforceable." All other applicable requirements unless otherwise indicated are both state and federally enforceable.

The inherent complexity of this facility coupled with the fact that the majority of process units are major sources themselves, has necessitated this permit to be structured in several parts. Accordingly, the attached operating permit- Part 2, satisfying the requirements of Regulation No. 30, covers only a partial list of processes. The processes covered by Part 2 of the permit are discussed in this memo. They are labeled Sections A through O in Table 1 beginning on page XX.

I. Glossary of Abbreviations and Acronyms Used

Air Quality Management	AQM
Alkylation Unit	ALKY
Ambient Air Quality Standards	AAQS
Air Pollution Control Device	APCD
Alternate Monitoring Plan	AMP

Baghouse	BG
Barrels per Hour	BPH
Barrels per Day	BPD
Barrels per Year	BPY
Batch Process	BP
Best Available Control Technology	BACT
Carbon Canister	CC
Carbon monoxide Boiler	COB
Catalytic Hydrodesulfurizer Unit	CHU
Clean Air Act Amendments	CAAA
Code of Federal Regulations	CFR
Continuous Catalyst Regeneration	CCR
Continuous Emissions Monitoring System	CEMS
Continuous Emissions Rate Monitoring System	CERMS
Crude Unit	CU
Cylinder Gas Audit	CGA
Delaware City Refinery	DCR
Department of Natural Resources and Environmental Control	DNREC
Diethanolamine	DEA
Diglycolamine	DGA
Dissolved Nitrogen Floatation	DNF
Emissions Offset Program	EOP
Ether Plant	EP
Ethyl Tertiary Butyl Ether	ETBE
Excess Emissions Report	EER
Facility Wide Requirement	FWR
Flare Gas Recovery	FGR
Fluid Catalytic Cracking Unit	FCCU
Fluid Coking Unit	FCU
Frozen Earth Storage	FES
Gasoline Dispensing Facility	GDF
Good Engineering Practice	GEP
Hazardous Air Pollutant	HAP
Hydrocracker Unit	HCU
Hazardous Organic NESHAP	HON
Hydrogen Plant	HP
Lowest Achievable Emission Rate	LAER
Leak Detection and Repair	LDAR
Marine Vapor Recovery	MVR
Material Safety Data Sheets	MSDS
Maximum Achievable Control Technology	MACT
Methyl tertiary butyl ether	MTBE
National Ambient Air Quality Standard	NAAQS
National Emission Standards for Hazardous Air Pollutants	NESHAP
New Source Performance Standards	NSPS
New Source Review	NSR
Oil Recovery System	ORS
Olefins Plant	OP
Polymerization Unit	POLY
Potential to Emit	PTE
Prevention of Significant Deterioration	PSD

Reasonably Available Control Technology	RACT
Refinery Flare System	RFS
Refinery Gas Plant	RGP
Refinery Tank Farm	RTF
Reformer/Reformulated Gasoline 2000 Project	RFG2K
Relative Accuracy Test Audit	RATA
Selective Hydrogenation Unit	SHU
Shell Claus Offgas Treatment Unit	SCOT Unit
Selective Non Catalytic Reduction	SNCR
Spent Caustic Stripper	SCS
South Coke Storage Area	SCSA
Steam Methane Reformer Hydrogen Plant	SMRHP
Sulfur Recovery Area	SRA
Synthetic Organic Chemical Manufacturing Industry	SOCMI
Tertiary amyl methyl ether	TAME
Tank with fixed cone roof	TC
Tank with floating roof	TF
Total annual benzene	TAB
Vapor combustion unit	VCU
Vapor Recovery Unit	VRU
Volatile Hazardous Air Pollutant	VHAP
Volatile Organic Compound	VOC
Wet Gas Scrubber	WGS
Waste Water Treatment Plant	WWTP

II. **Background**:

Premcor owns and operates the Delaware City Refinery (DCR), NAICS Code 32411, located on a 5,000 acre tract in Delaware City and between US Route 13 and Delaware Route 9. The DCR has the potential to emit greater than 25 tons per year NO_x and VOCs, greater than 100 tons per year SO_2, greater than 100 tons per year CO, and greater than 25 tons per year hazardous air pollutants (HAPS) listed in Section 112(b) of the CAAA of 1990. Therefore, the DCR is subject to Regulation 30. The DCR was owned by Star Enterprises at the time the title V application was submitted to the Department. On July 1, 1998, Shell Oil Products (Shell), Saudi Refining, Inc., and Texaco Inc. formed Motiva, combining the major elements of Shell's and Star's eastern and southern refining and marketing businesses. The ownership of Star Enterprise was transferred to Motiva L.L.C. on October 1998. In October 2001, Texaco Inc. divested itself of its share in the Company. Motiva sold the DCR to The Premcor Refining Group, Inc. on May 1, 2004. On September 1, 2005, Premcor, in turn, was acquired as a wholly owned subsidiary by The Valero Energy Corporation (Valero).

The first step in the refining process is the separation of crude feedstock into fractions determined by the boiling point of the respective constituents of the crude. This process is accomplished in the Crude Unit (CU). The heaviest fractions are further processed in the Fluid Catalytic Cracking Unit (FCCU), the Hydrocracker (HC) and the Fluid Coking Unit (FCU). Lighter fractions are processed in units such as the Gas Plant, Alkylation and Polymerization (Alkypoly) Unit, Cracked Naphtha Hydro-Treating Unit (CNHT), Continuous Catalytic Regeneration (CCR) Reforming Unit, Catalytic Hydrodesulfurizing Units (CHU), Sulfur Recovery Area (SRA) and other auxiliary refinery process systems. Air pollution emissions from the DCR can be classified under two categories, i.e., point source emissions from combustion equipment and process vents, and fugitive emissions. Because the project consists of numerous processes, this regulatory and technical review has been structured to address each process separately. The regulatory review of each process begins with a process description followed by identification of all applicable requirements and determination of the standards with which the process must comply. The technical review addresses the basis for these

emission limits and the appropriate monitoring, record keeping and reporting requirements that go with each process. Table 1shows the various DCR unit operations (Unit No.), the relevant Part of the Title V permit where each unit operation is covered (Permit Section), the relevant section in this memorandum (Memo Section), and a brief description of each unit operation.

Identification of Emission Units:

Table 1: Refinery Process Units

Unit No.	Permit Section	Memo Section	Description of Process Equipment and Emissions Units
10	Part 2	A	Waste Water Treatment Plant (WWTP), Vapor Combustion Unit (VCU), and the Gasoline Dispensing (GD) Facility
15	Part 2	B	Marine Piers for product loading and crude receiving and two ground level flares
21	Part 2	C	Crude Unit (CU) consisting of Atmospheric and Vacuum Heaters (21-H-701 and 21-H-2), Sour Water Treater (SWT), and Crude Coker Gasoline Merox Treater
22	Part 2	D	Fluid Coking Unit (FCU) consisting of Coker Feed Tank Heater (40-H-1), FCU Reactor, FCU Burner, FCU Scrubber, Gas Plant Fractionator, Start Up Air Heater (22-H-1), Selas Steam Superheater (22-H-2), FCU Carbon Monoxide Boiler (COB) (22-H-3), Back Up Incinerator (22-H-4) and Coke Storage and Handling
23	Part 2	E	Fluid Catalytic Cracking Unit (FCCU) consisting of Start Up air Heaters (23-H-1A/B), Feed Pre-heater (23-H-2), Catalyst Storage and Handling Equipment, FCCU Riser, FCCU Reactor, FCCU Regenerator and FCCU COB (23-H-3)
24	Part 2	F	Gas Plant consisting of the Diglycol Amine (DGA) Treater and the Alkylation Unit Merox Treater
25	Part 2	G	Cracked Naphtha Hydrotreater (CNHT), CNHT Reboilers, Butamer Unit and Cooling Tower
26	Part 2	H	Polymerization Unit
27	Part 2	I	Alkylation Unit
28	Part 2	J	Sulfur Recovery Area consisting of Claus Units SRU I and SRU II, the Shell Claus Offgas Treatment Units I and II with Waste Heat Boilers, and the Stack Incinerators.
29	Part 1	-	Hydrodesulfurization Unit consisting of 5 trains with process heaters (29-H-2 through 29-H-9 and 29-H-101)
32	Part 1	-	Tetra Unit consisting of Tetra Feed Heater (32-H-101), Feed Preparation Column Bottoms Heater (32-H-102), Tetra Unit Heater (32-H-103) and the Benzene Transfer Operations and Benzene Storage, the Toluene Process, and the Aromatics Fractionation Process
33	Part 1	-	Selective Hydrogenation Unit consisting of the Selective Hydrogenation Process, the Start Up Heater 33-H-1 and the Reboiler Heater 33-H-2.
34	Part 1	-	Olefins Plant consisting of process, loading operations and Olefins Unit Reboiler (34-H-101)

Unit No.	Permit Section	Memo Section	Description of Process Equipment and Emissions Units
36	Part 1	-	Hydrocracker Unit consisting of the Hydrocraker feed Heater (36-H-1), the Hydrocraker Vacuum Column Reboiler (36-H-2) and the Hydrocraker Fractionator Reboiler (36-H-3)
37	Part 2	K	Hydrogen Plant consisting of the Carbon Drum Vent which vents to the flare and the Process Heater (37-H-1)
40	Part 1	-	Refinery Tank Farm consisting of various storage tanks categorized under 11 groups and the Frozen Earth Propane Storage
42	Part 2	L	Continuous Catalyst Regeneration (CCR) Reformer consisting of the Reforming Process, the CCR Platform Heater (42-H-1,2,3) and the CCR Reformer Reboiler (42-H-7)
45	Part 2	M	Utilities consisting of the Flare System, Spent Caustic Stripper, Ammonia Storage and the Boiler Feed Water Treatment Plant
80	Part 3	-	Delaware City Power Plant (DCPP) Boilers 1, 2, 3 and 4 (80_1, 80_2, 80_3 and 80_4).
82	Part 3	-	Two Texaco Gasifiers (82_1a and 82_2a) and two Gas Coolers (82_1b and 82_2b).
82	Part 3	-	Amine Acid Gas Removal System 82_3, Syngas Flare 82_4.
50	Part 3	-	Three-Cell Linear Mechanical Draft Evaporative Cooler.
84	Part 3	-	Combined Cycle Gas Turbine Units (CCUs) 84_1 and 84_2.
FWR	Part 2	N	Facility Wide Requirements

DCR's original Title V application was signed by Mr. P. M. Laabs, the Plant Manager of the facility in 1996, who met the requirements of being a "Responsible Official" as defined in Regulation No. 30, Section 2. Due to the ownership transfers in the interim years to Motiva followed by Premcor and finally Valero, the representations and responsibilities of the previous Plant Manager pertaining to this Title V permit are now transferred to Mr. Andrew Kenner, Vice President and General Manager, who meets the requirements of being a "Responsible Official" as defined in Regulation No. 30, Section 2.

The facility is subject to the requirements of Section 112(r) of the 1990 Clean Air Act Amendments and has registered with the State of Delaware "Regulations for the Management of Extremely Hazardous Substances." The facility has paid applicable fees associated with Regulation 30.

The facility has requested that information contained in Form AQM1001B/1 regarding the maximum hourly and yearly inputs and outputs of raw materials and products be considered confidential information. This information has been stamped "confidential" and a sanitized copy minus these pages will be made available for public review.

Chronology of Correspondence:

Table 2 provides a chronology of correspondence applicable for Part 2 under the present ownership[1].

Date	Description
October 31, 2007	AQM 1001 Series Application (Revision 9)

[1] The complete list including the chronology of correspondence from past owners is incorporated by reference.

III. General:

Table 3 shows the applicable requirements common to all units covered under Part 2.

Applicable Requirements corresponding to all emission units in Part 2 (including insignificant activities) at the facility:

Table 3: Facility Wide Applicable Requirements

Applicable Requirement	Condition Identification in Draft Title V Operating Permit and Description	
	Condition Identification	**Description**
Regulation No. 3	Condition 2(b)(7)	None proposed
Regulation No. 14	Section 2.1 is applicable facility wide (excluding emission points already covered under title V part 1 issued on November 14, 2001, EP 23-1 and EP 45-1 and 2.. This facility wide condition is located in the Part 2 permit as Condition 3 Table 1, condition ob.1.i.	All Title V Part 2 units with stacks are subject to an opacity limitation. All process heaters fire only desulfurized RFG or natural gas and are unlikely to cause opacity exceedances during normal operation. However, opacity exceedances can occur during process upsets. Therefore, it is reasonable to require the Company to make qualitative opacity observations on a daily basis and conduct visible emissions evaluations for a given process whenever these observations indicate a likelihood of opacity occurrences. For all the other units, i.e., those not specifically identified in this Table, a facility wide opacity condition is included in Condition 3 Table 1, condition n.1.i.
Regulation No. 17	Section 2.2 - Condition 3(b)(1)(ii)	None proposed
	Section 7 - Condition 3(c)(2)(iv)	None proposed
Regulation No. 19	Section 2.1 - Condition 3 Table 1 , condition ob.2.i is applicable facility wide for the emission units covered under Part 2	This Title V permit condition is state enforceable only and is applicable on a facility wide basis.
Regulation No. 24	Section 8 - Handling, Storage, and Disposal of VOCs. Is applicable for for the emission units covered under Part 2. Addressed in Part 2 Permit in Condition No. 3 - Table 1, condition ob.3.	Records of postings and employee training related to the work practice standards of this regulation. Additional monitoring is not proposed since Regulation No. 30 Section 6(a)(3)(i)(B) states that recordkeeping can be sufficient for periodic monitoring.

Applicable Requirement	Condition Identification in Draft Title V Operating Permit and Description	
	Condition Identification	**Description**
	Section 28 - Petroleum Refinery Sources. Permit Condition No. 3 - Table 1, condition ob.4 for all applicable systems.	Vapors shall be compressed and added to fuel gas system; any uncondensed vapors will be routed to a firebox or process heater for destruction. During process turnarounds, there shall be no emissions of VOCs from a process unit or vessel until its internal pressure is less than 136 kPa.
	Section 29(c) to Section 29(i) monitoring requirements, i.e., the Leak Detection and Repair (LDAR) program for equipment in VOC service. Condition No. 3 - Table 1, condition ob.5.	The Company shall comply with the monitoring standards specified in Sections 29(c) through 29(h) of Regulation 24. The Company shall comply with test methods and procedures specified Regulation 24, Section 29(i) and Appendix "F".
	Section 40 test methods and procedures, work practice standards, record keeping and reporting requirements for the refinery SOCMI sources. Condition No. 3 - Table 1, condition oa.1 through oa.13.	The Company shall comply with the LDAR program for the SOCMI sources.
	Section 50 test methods and procedures, work practice standards, record keeping and reporting requirements. Condition No. 3 - Table 1, condition ob.6.	This is the applicable requirement for non-CTG RACT sources within the refinery.
40 CFR Part 63 Subpart CC	This subpart applies to petroleum refining process units and to related emission points that are specified in paragraphs c(5) through (c)(7) of Section 63.640 that are located at a plant site that meet the following criteria [Condition No. 3 - Table 1, condition oa.1 through oa.13]: ! Are located at a plant site that is a major source as defined in section 112(a) of the CAA; and ! Emit or have equipment containing or contacting one or more of the hazardous air pollutants listed in Table 1 of Subpart CC.	The Company shall comply with the following standards: § 63.642 for miscellaneous process vents; § 63.646 for storage vessels; § 63.647 for wastewater streams § 63.648 for equipment leaks detection § 63.651 for marine vessel loading operations

IV. **Emission Units**:

Process Descriptions:

A. Waste Water Treatment Plant (WWTP) - Unit 10

The WWTP was constructed in 1956 and was modified in 1995 to comply with the benzene NESHAP regulations. Additional modifications were completed in 2001 to comply with the requirements of the 2001 state consent decree[2]. Included in the discussion under this section are the following units:

- Oily sewer system that carries refinery waste water to the WWTP and oil recovery system.
- Sealed Corrugated Plate Interceptor (CPI) Separator with fixed roof with passive venting to a carbon adsorption system.
- American Petroleum Institute (API) Separator with floating roofs on each of four oily water bays and on one chemical sewer bay. The portions of the API separator that are equipped with fixed roofs vent to a carbon adsorption system.
- Two equalization tanks, 323-TF-136 and 324-TF-136 (5.7 million gallons each), a spill diversion tank, 313-TF-48 (2 million gallons), two flocculator tanks, 304-TF-136 and 325-TF-136, all equipped with external floating roofs with double seals.
- One flash mix tank with a fixed roof venting to a carbon adsorption system.
- A vapor combustion unit (VCU) with a design heat input of 89.5 mmBtu/hour constructed in 1994 to control VOC emissions from one crude oil recovery tank (372-TC-M), one sludge holding tank (349-TC-M), three dissolved nitrogen floatation tanks (305-TC-M, 306-TC-M and 326-TC-M), three day tanks (356-TC-3, 357-TC-3, and 358-TC-3), two slop oil tanks (10-D-109 and 10-D-202), one recovered oil tank (359-TC-M), and vacuum filters when processing wet oil.
- One gasoline dispensing facility constructed in 1994 for refinery fleet vehicles. comprised of one 4,000 gallon gasoline storage tank with a dual point Stage I vapor recovery system and a Healy Stage II vapor recovery system for the gasoline dispenser. This facility dispenses about 10,000 gallons per month.

Waste water from various refinery processes is conveyed to the WWTP through the sewer system. The major uses of water in petroleum refining are steam generation and heat transfer. The volume of water coming into direct contact with process streams is small compared to the volume used for cooling and heat transfer. However, almost every refinery process produces waste water containing various pollutants. Refinery waste water typically contains oil, phenols, sulfides, ammonia and dissolved and suspended solids. There are three main sewers used to convey waste streams from the refinery to the WWTP in the following manner:

- Storm sewer with a design capacity of 5.1 MGD. The storm sewer leads to the storm sewer CPI separator where wet oil and bottoms are removed. The wet oil is routed to wet oil processing and the bottoms led to the sludge holding tank. Effluent from the storm sewer CPI flows to the equalization tanks.
- Chemical sewer with a design capacity of 0.3 MGD. The chemical sewer leads to the API separator chemical bay where bottoms and wet oil are removed. The effluent flows to the equalization tanks.
- Oily waste sewer with a design capacity of 6 MGD. Inactive manholes along the oily sewer are sealed and VOC emissions from passive venting manholes are routed to carbon canisters control devices. The oily sewer leads to oily sewer CPI followed by the 4 oily bays of the API separator. Effluent is routed to the equalization tanks.

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[2] These additional modifications were required pursuant to paragraphs 13 through 15 of Civil Action No. 18750 NC between Nicholas A. DiPasquale, Secretary of the Department of Natural Resources and Environmental Control, Plaintiff, versus Motiva Enterprises, LLC, Defendant, entered on March 26, 2001 in the Court of Chancery of the State of Delaware in and for New Castle County.

Treatment of waste water at the WWTP can be classified as follows:

- Primary treatment, designed for oil/water separation and removal of settleable solids. Primary treatment is carried out in the API and CPI separators, both of which utilize gravity separation techniques to remove oil, oily sludge, and grit from the influent. The oily waste from the process units or from the sour water stripper[3] are processed by the two gravity separators where up to 99 percent of the free oil is removed.[4] The API separator has five bays which are long rectangular tanks where continuous laminar flow is maintained. A system of baffles aid in separation of the oil from the water. Scrapers mounted on a chain and flight mechanism move the oil to one end of the separator where a slotted pipe collects it. The supernatant flows over a weir at the other end to downstream units for further processing. The CPI separator chamber is subdivided by parallel plates inclined at 45 degrees and less than 6 inches apart. This configuration increases the oil collection area, thus decreasing the overall size of the unit. As waste water flows through the CPI, oil droplets coalesce on the undersides of the plates and travel upwards for collection.
- Intermediate treatment begins with an equilibrium holding section having several hours of retention time to allow leveling of hydraulic and contaminant concentration surges. This is accomplished by means of the two equalization tanks, 323-TF-136 and 324-TF-136 (5.7 million gallons each). In addition, a spill diversion tank, 313-TF-48 (2 million gallons) provides additional storage capacity during periods of very heavy flow. All are equipped with external floating roofs with double seals. A flash mix tank is provided downstream of the equalization tanks to ensure good mixing with a coagulant before the waste stream flows to two flocculator tanks, 304-TF-136 and 325-TF-136. The flash mix tank is a fixed roof tank that vents to a carbon adsorption system. The flocculator tanks have external floating roofs with double seals. From the flocculator tanks the waste stream flows to thee dissolved nitrogen floatation (DNF) tanks, 305-TC-M, 306-TC-M and 326-TC-M. The DNF process consists of saturating nitrogen gas in the waste water by pressurizing the waste water to between 40 and 60 psig. When the pressure is released, the gaseous nitrogen comes out of solution in the form of minute bubbles. Because of the entrained nitrogen gas, particulate matter and oil droplets have greatly increased vertical rise rates (0.15 m/min to 0.3 m/min). In rising to the surface, particulate matter and oil agglomerate and form a froth layer which is skimmed off and led through a oily sludge holding tank to three wet oil holding tanks. Oil from the wet oil holding tanks flow to a cuff oil tank from where it is fed to the coker unit. All DNF tanks, the wet oil tanks, cuff oil tanks, and the recovered oil tank vent to the VCU.
- Secondary treatment begins when the effluent from the DNF tanks flows to the secondary treatment section consisting of floatation clarifiers followed by a two stage aeration and clarification stage. Activated sludge is recycled from each clarifier to the aeration tank. Bio-sludge from the clarifiers is routed to the refinery landfill through a set of three vacuum filters. The supernatant flows through sand filters to the outfall (guard basin # 4). The vacuum filters vent to the VCU[5].

B. Marine Vapor Recovery (MVR) – Unit 15

The marine piers located along the Delaware River were constructed in 1956. The MVR system was constructed in 1995. The MVR consists of two (2) John Zink Vapor Combustion Units (VCUs),

[3] Sour water strippers provide inplant pretreatment where steam is used as a stripping medium to remove hydrogen sulfide, ammonia and phenols from the waste stream. Removal of these chemicals from the waste water before it is treated at the WWTP can greatly reduce the COD and BOD at the treatment plant.
[4] EPA: Petroleum Refinery Enforcement Manual; Section 4.21, EPA-340/1-80-008, March 1980.
[5] The VCU is considered an enclosed combustion device needing to comply with 40 CFR 61.349. The operating temperature of the VCU is maintained at around 1300EF. At this temperature, HAP emissions are below the regulatory limit of 20 ppmv on a dry basis at three percent (3%) O_2. Propane is the supplemental fuel for the VCU.

Model ZCM-3/5/5-12-65- 2/8-4/8-4/8-2 WO Stacks. These enclosed flares have a rated capacity of 4094 SCFM and a vendor guarantee of 98 % VOC destruction. The VCUs are equipped with heat sensing devices that continuously indicate the presence of a flame at the pilot. The Marine Vapor Recovery Vapor Combustion Unit (MVR VCU) System is designed to collect and process a vapor stream resulting from the loading gasoline at 35,000 Barrels per Hour (BPH) combined rate at both piers (Pier 2 and Pier 3) or maximum of 25,000 BPH loading rate at a single pier. The system consists of 3 main processes: a) a collection system with an in-line blower rated at 50 hp, that pulls the vapor from the vessel being loaded into a detonation arrestor; b) a gas enrichment system that injects natural gas into the vapor stream after the arrestor, to elevate the vapor concentration above its upper explosive limit; and c) 2 Vapor Combustion Units (VCUs) that combust the vapor/natural gas once the entrained liquids are removed and the gas stream is isolated from a source of ignition. A pressure vacuum is located upstream of the detonator (flame arrestor) which opens to a vacuum of 8 ounces and relieves pressure at 16 ounces, gage. Oxygen levels are measured during barge loading to ensure that the vapor does not reach its upper explosive limit. Natural gas is injected into the system to elevate the vapor concentration above this limit and provide heat release for the flare. The system will shut down if the oxygen level reaches 16%. However, at the instant loading commences, oxygen levels are higher than 16% because the empty barges are not normally filled with an inert gas such as nitrogen. A Program Logic Circuit (PLC) prevents shutdown during the early stages of loading (typically < 5 min).

C. Crude Unit – Unit 21:

The crude unit was constructed in 1956 is comprised of the following processes:

- Desalters.
- Sour water stripping plant. There are no direct emissions from the sour water stripping plant. However, storage vessels (470-TF-50 and 471-TF-50) used to store sour water have he potential to emit VOCs as well as malodorous contaminants. These two tanks have been addressed in Part 1 of the Title V Permit. In addition, ammonia waste stripped from the sour water in 21-C-303 is routed to the SRA where it is destroyed.
- Atmospheric heater 21-H-701, and the atmospheric distillation tower. Emissions from 21-H-701 are vented through emission point 21-1. There are no direct emissions from the atmospheric tower.
- Vacuum heater 21-H-2 and the vacuum distillation tower. Emissions from 21-H-2 are vented through emission point 21-1. There are no direct emissions from the vacuum tower.
- Merox treatment unit. Spent merox air is vented to the firebox of unit 21-H-701 or to unit 28-S-202 in the SRA.

The crude unit is the first important unit operation in the refinery. This operation includes heating, vaporization, fractionation, condensation and cooling, thereby separating incoming crude oil into various boiling fractions. The crude unit accomplishes the distillation in two stages - the total crude is fractionated in an atmospheric tower and the high boiling bottoms are further fractionated in a vacuum tower. The incoming crude is desalted and heated to 650 EF in the atmospheric heater unit (21-H-701). The crude flows to the main fractionator where various boiling fractions are separated. The atmospheric tower bottoms are heated in the vacuum tower heater (21-H-2) and further fractionated in the vacuum tower. Desalted effluent water is stripped and the overhead is routed to the sour water stripping plant where acid gas (H_2S and NH_3) are removed. The H_2S and NH_3 are routed to the SRA. Unit 21-H-701 is fired by RFG to heat the incoming crude oil to about 400 EC prior to feeding the crude stock to the main atmospheric distillation column. The process heater is vertically fired and has a horizontal tube radiant section in two separate furnace cells. There is a convection section and steam superheat coil at the top of the heater that is common to both furnace cells. There are two flue uptakes from the process heater leading to a stack shared with the Vacuum Heater Unit 21-H-2. The two heater units also presently share common NO_x and CO_2 analyzers. Unit 21-H-2 fires either refinery fuel gas or No. 6 oil. There are 8 burners per side all of which are capable of firing either fuel.

Finally, because gasoline produced in the crude unit has a high sulfur content in the form of mercaptans and thiols, it must be sweetened. The light straight run (LSR) gasoline from the atmospheric tower and the coker gasoline containing similar sulfurous impurities are sweetened in a portion of the crude unit called the Merox treater. This is essentially an oxidation process where thiol sulfur is converted to a disulfide. This is done by contacting the sour gasoline with a caustic solution containing the Merox catalyst to extract the mercaptans. The extracted gasoline is sweetened by reacting it with air in the presence of Merox-containing caustic solution. Spent merox air is routed to the furnace of unit 21-H-701 or to the sulfur plant as an alternate control device. The sour water generated by the crude desalting process is led to tankage in Tank 471. From tank 471, sour water is stripped in the sour water stripper. Stripped H_2S is led to the sulfur plant for sulfur recovery.

D. Fluid Coking Unit (FCU) and Coke Handling Operations – Unit 22:

The FCU is comprised of the following units/processes:

- FCU reactor, scrubber and burner and start up air heater (22-H-1) with a rated design heat input of 107 mmBtu/hour.
- FCU Selas steam superheater (22-H-2) with a rated design heat input of 17.8 mmBtu/hour.
- FCU COB (22-H-3) with a rated design heat input of 674.7 mmBtu/hour, GE SNCR System, Belco Pre-scrubber, Cansolv Absorber and Caustic Polisher
- FCU back up incinerator (22-H-4) with a rated design heat input of 942 mmBtu/hour.
  Coke storage and handling facility

The FCU allows the refinery to process low cost, high sulfur crude oil to produce high value products such as gasoline, thereby increasing profitability. Vacuum residuum from the vacuum distillation tower of the Crude Unit is the main feedstock to the FCU. This feed enters the scrubber section of the FCU where it is blended with cooled recycle oil. Recycle oil is blended oil at the bottom of the scrubber that has been used to scrub out coke particulate matter. About 66 % of this combined recycled scrubber oil is fed to the reactor through three inlet distribution rings having a total of 42 feed injection nozzles. The feed thus comes into contact with hot coke in the reactor (about 980EF) and breaks up into smaller chains of hydrocarbons by the process of thermal cracking. The coke bed is kept in a fluidized state by injection of fluidizing steam at 175 psig and 750E F through 37 steam nozzles. Cold coke at about 950EF is drawn from the bottom of the reactor and returned to the burner where combustion air is supplied to burn the coke partially and generate the heat necessary to sustain the endothermic cracking reaction in the reactor. The hot coke is withdrawn through an overflow well and is fed to the reactor to continue the cracking operation. Excess product coke is withdrawn through a quench elutriator prior to its being conveyed by conveyor belts to a storage area on site north of the DP&L powerhouse. About 1.5 tons per minute of product coke leaves the elutriator at 425EF. Scrubber overhead at a rate of 350 tons per hour is fed to the bottom of the main Fractionator (Column C-1). Light gas oil is condensed and refluxed with additional gas oil and fed to either the Hydrocracker or the FCCU as feed. Tower bottoms are refluxed to the top of the scrubber and overheads flow to a flash drum and accumulator which allows the separation of gas, fractionator overhead liquid and water. About 200 tons per hour of wet gas is produced. Coker gasoline is extracted from the accumulator and split into fractionator reflux and excess going to the flash drum. The latter is heated and flashed with the vapors being condensed and sent to the absorber/stripper column where the liquid is extracted and pumped to storage for use as feed to the FCCU. The burner unit contains about 350 tons of coke. The circulation of this coke through the reactor and back to the burner is controlled by two slide valves that achieve precise control. The stoichiometry for the combustion process in the burner unit is as follows:

$$2\ C + O_2 \equiv 2\ CO;\ )H = -\ 110.5\ kJ/mol$$

During periods of start up, an air heater (Unit 22-H-1) rated at 107 mmBtu/hour is used to supply the heat necessary to initiate the combustion stoichiometry given above. This unit fires only refinery fuel gas and is supplied by a forced draft fan.

In order to keep the coke fluffed, an auxiliary refinery fuel gas fired steam superheater called the Selas Steam Superheater (Unit 22-H-2) is provided. This unit is fired continuously and provides 175 psig steam that is injected at strategic points with the aid of special steam injection nozzles. Unit 22-H-2 is rated at 17.8 mmBtu/hour and uses 12 mmSCF/month of refinery fuel gas.

Burner flue gas exits through 18 two-stage cyclones and flows to one of two water seals before entering the CO boiler and the downstream wet gas scrubber (WGS) train. The COB houses an ammonia based selective non-catalytic reduction (SNCR) system. The SNCR process involves injection of 19.5 % solution of ammonia into the COB combustion gases. When the desired temperature and residence time is maintained the reagent will selectively react with the nitric oxide to reduce it to molecular nitrogen.

The amine-based regenerative WGS includes a water pre-scrubber, an amine-based regenerative scrubber and a caustic There are 2 main elements in the WGS – the scrubber and regeneration systems. The scrubber element consists of a Belco prescrubber followed by a Cansolv absorber section. The purpose of the Belco prescrubber is to saturate the flue gas with water and to remove particulate matter and sulfur trioxide before the gas enters the absorber section. The Belco prescrubber section consists of a quench section followed by Agglofilter modules and Cyclolab droplet separators. A low pH is maintained in the prescrubber section to maximize the SO_2 absorption in the absorber section. The quench and Agglofilter modules remove particulate matter and SO_3 while the Cyclolabs remove any large entrained droplets carried over from the prescrubber. Blowdown from the prescrubber flows to a purge treatment unit where it is neutralized with caustic and clarified prior to being routed to the refinery's effluent treatment plant. The main SO_2 absorption section of the Belco/Cansolv WGS uses an amine-based scrubber solution in a packed bed absorber tower to remove SO_2 from the exhaust stream. The main absorption loop is followed by a polishing scrubber, which is a final packed stage that is separate from the amine-based absorption step and will be used to ensure that the CD driven levels of control are achieved (i.e., 25 ppmvd @ 0 % O_2 on a 365 day rolling average basis and 50 ppmvd @ 0 % O_2 on a 7 day rolling average basis). A packed tower serves as the absorber where the gas is contacted with an amine which absorbs the SO_2. Cleaned gas exits the absorber through a stack mounted on the absorber tower. Rich amine is filtered and heated through an effluent-influent heat exchanger before being fed to the regenerator tower. In the regenerator, the rich amine is steam stripped yielding a high purity SO_2 stream that will be routed to the refinery's SRA. The regenerated lean amine is pumped back to the absorber. Because heat stable salts (HSS) are formed over time, a small slip stream of lean amine is routed to an electro-dialysis unit to extract the HSS from the lean amine.

During periods of start up, shut down and malfunctions in either the COB or the WGS, both these unit operations are bypassed and the flue is routed either to a bypass stack or through the back up incinerator fired by RFG.

E. **Fluid Catalytic Cracking Unit (FCCU) – Unit 23**:

An integral part of refining operations involves a chemical decomposition process whereby gas oil (heavy distillate) carbon chains are broken down in the presence of heat and a catalyst into lighter fractions, thus increasing the gasoline yield from the crude stock. This decomposition is carried out in the FCCU. The cracking takes place when fresh feed comes in contact with hot catalyst in a riser tube. The catalyst and cracked products flow to a reactor where they are disengaged, the products flowing to a fractionator for further processing. The spent catalyst rises through two internal risers to a regenerator where the coke that is deposited on the catalyst is burnt under controlled combustion

conditions. The regenerated catalyst is withdrawn and fed to the riser to repeat the process. Regenerator combustion products contain regulated criteria pollutants and therefore must be controlled before being released to the atmosphere. Pollutants in this off-gas include particulates (from catalyst fines), carbon monoxide, sulfur dioxide, nitrogen oxides, HAPs and VOC. Control measures include internal cyclones for particulate removal, a carbon monoxide boiler to combust the carbon monoxide to carbon dioxide, ULNBs to reduce COB NO_x emissions, a Belco prescrubber to control PM_{10} and H_2SO_4 emissions and an amine based regenerative WGS to control SO_2 emissions.

FCCU feedstocks are complex mixtures of hydrocarbons of various types and sizes ranging from small molecules with four carbon atoms to very large complex molecules of perhaps 60 carbon atoms. The crackability of a particular feedstock is a function of the relative proportions of paraffinic, naphthenic and aromatic species in the feed. The generally accepted theory behind catalytic cracking reactions is based on the formation of carbenium ions. Once formed, the carbenium ion is most likely to crack by ∃ scission. In other words, the C-C bond in the ∃ position relative to the positively charged C tends to be cleaved. The olefin may now form a new corbonium ion with the catalyst, thus propagating the reaction. Spent catalyst containing coke is regenerated in the regenerator under sub-stoichiometric conditions thereby producing CO.

Regenerator flue gas exits through 14 two-stage cyclones and flows to the CO boiler and the downstream wet gas scrubber (WGS) train. The amine-based regenerative WGS includes a water pre-scrubber, an amine-based regenerative scrubber and a caustic There are 2 main elements in the WGS – the scrubber and regeneration systems. The scrubber element consists of a Belco prescrubber followed by a Cansolv absorber section. The purpose of the Belco prescrubber is to saturate the flue gas with water and to remove particulate matter and sulfur trioxide before the gas enters the absorber section. The Belco prescrubber section consists of a quench section followed by Agglofilter modules and Cyclolab droplet separators. A low pH is maintained in the prescrubber section to maximize the SO_2 absorption in the absorber section. The quench and Agglofilter modules remove particulate matter and SO_3 while the Cyclolabs remove any large entrained droplets carried over from the prescrubber. Blowdown from the prescrubber flows to a purge treatment unit where it is neutralized with caustic and clarified prior to being routed to the refinery's effluent treatment plant. The main SO_2 absorption section of the Belco/Cansolv WGS uses an amine-based scrubber solution in a packed bed absorber tower to remove SO_2 from the exhaust stream. The main absorption loop is followed by a polishing scrubber, which is a final packed stage that is separate from the amine-based absorption step and will be used to ensure that the CD driven levels of control are achieved (i.e., 25 ppmvd @ 0 % O_2 on a 365 day rolling average basis and 50 ppmvd @ 0 % O_2 on a 7 day rolling average basis). A packed tower serves as the absorber where the gas is contacted with an amine which absorbs the SO_2. Cleaned gas exits the absorber through a stack mounted on the absorber tower. Rich amine is filtered and heated through an effluent-influent heat exchanger before being fed to the regenerator tower. In the regenerator, the rich amine is steam stripped yielding a high purity SO_2 stream that will be routed to the refinery's SRA. The regenerated lean amine is pumped back to the absorber. Because heat stable salts (HSS) are formed over time, a small slip stream of lean amine is routed to an electro-dialysis unit to extract the HSS from the lean amine.

During periods of start up, shut down and malfunctions in either the COB or the WGS, both these unit operations are bypassed and the flue is routed to a bypass stack. During such periods, a catalyst promoter is added to the regenerator the initiate complete combustion in the regenerator.

F. Refinery Gas Plant – Unit 24

The refinery gas plant separates lighter hydrocarbon intermediates from the FCCU and other process units into hydrocarbon fractions for further processing and for internal and external use. The RGP serves the entire refinery as a source of fuel gas and as a unit where light hydrocarbon intermediates are sent for processing. The diglycolamine (DGA) fuel gas treater and the Alkylation Unit Merox

Treater are the two sources in the RGP. The DGA removes H_2S from the RFG and sends it to the sulfur recovery area for recovery of elemental sulfur. The Alkylation Unit Merox Treater treats the alkylation unit feed stream. Its spent air is sent to the FCCU COB.

G. Reformer and Reformulated Gasoline 2000 (RFG 2K) Project – Unit 25

The RFG 2000 Project is comprised of a Naphtha Hydrotreater (CNHT) Reactor Charge Heater, 25-H-401; CNHT Unit Reboiler Heater, 25-H-402; CNHT Unit, Butamer Unit, and Cooling Tower. The RFG 2000 Project produces gasoline that meets federal requirements for reformulated gasoline. Its purpose is to reduces the gasoline sulfur content year-round by hydrotreating a larger fraction of the gasoline pool's cracked naphtha streams, it reduces the gasoline olefin content year round by olefin hydrogenation, reduces the gasoline Reid vapor pressure during the ozone season by debuatizing a portion of the gasoline pool, isomerizes the butane to iso-butane and uses the iso-butane as feed to the alkylation unit and hydrotreats the additional gasoline pool streams by the hydrotreatment of the cracked naphtha stream. Gasoline pool sulfur and olefin content are reduced by hydrodesulfurization and olefin-hydrogenation of the cracked naphtha produced by the FCCU and FCU. The CNHT unit was constructed from existing equipment in the old Reformer Train A (Unit 25) and new equipment comprised of a reactor charge heater (25-H-401) rated at 107 mmBtu/hour, and a reboiler heater rated at 78.7 mmBtu/hour. Cracked naphtha feed from the TAME Unit depentanizer column is preheated in an effluent-influent heat exchanger before being heated in charge heater 25-H-401. It is then combined with hydrogen upstream of the selective hydrogenation reactor, where hydrogen reacts with unsaturated hydrocarbon sites of the cracked naphtha, significantly reducing its olefin content. The hot hydrogenated naphtha passes through two desulfurization reactors where hydrogen reacts with the sulfur in the naphtha to form hydrogen sulfide (H_2S). The hot hydrogenated and desulfurized naphtha is cooled by heat exchange with the incoming feed and fed to the stabilizer section. n the stabilizer section, a fractionation tower recovers unreacted hydrogen which is recycled back to the reactors. A reboiler heater provides the heat necessary to maintain the temperature in the stabilizer column. Light hydrocarbons are separated from the hydrotreated naphtha which leaves the bottom of the column and flows to the naphtha sweetening unit. The sweetening unit is a liquid phase conversion process whereby mercaptan sulfur is converted to disulfides in the presence of caustic and air. Sweetened naphtha is routed to the blending unit and thence to product storage tanks.

Reduction in the Reid Vapor Pressure is accomplished by removing some of the butane from the process streams that feed the gasoline pool during the ozone season. The reaction section consists of two chloride activated precious metal catalytic reactors where *n*-butane is isomerized to iso-butane. Hydrogen is added to the *n*-butane from the debutanizer and undergoes isomerization in the reactors yielding about 60 % conversion to iso-butane. The additional iso-butane generated from the butamer unit is routed to the alkylation unit.

Cooling water for the process is supplied from a cooling tower which draws from the existing refinery cooling water effluent system. The water is cooled by contact with air in three linear mechanical draft evaporator cells and the cooled water is routed back to the process heat exchangers. It is sized to cool 30,000 gallons per minute.

H. Polymerization Unit – Unit 26:

Polymerization is a high pressure catalytic reaction of refinery gases such as propylene, propane, butylenes and butanes to produce polymer gasoline. The Polymerization unit itself has no emission points. However, a sweetening Merox unit generates a spent air stream which is routed to the firebox of a process heater in the Tetra Unit.[6]

[6] The destruction of the Poly Merox spent air stream in 32-H101 is permitted in Title V Part.

I. Alkylation Unit – Unit 27:

Alkylation is a reaction between an olefin and an iso-paraffin to produce tri-methly pentane, a component of gasoline that increases its octane rating. The alkylation unit uses sulfuric acid as a catalyst. The only air emissions from the alkylation unit are fugitive emissions.

J. Sulfur Recovery Area - Unit 28:

The SRA, was constructed originally in 1956 and modified in 1996 and again in 1998. It is comprised of 2 Claus units - SRU - I and SRU – II, each with a tail gas treatment (SCOT II and SCOT I). Acid gas is generated in the refinery at the amine scrubbing systems and sour water stripper. It is also generated at the gasifier gas cleaning system. All acid gas streams are fed to the SRUs to recover elemental sulfur. The primary constituent of the acid gas is Hydrogen sulfide (H_2S). The Claus process occurs in 2 steps. First, a portion of the H_2S is converted to Sulfur dioxide (SO_2) by combustion. Second, the remaining H_2S reacts with the newly formed SO_2 to produce elemental sulfur. These reactions are given by the following equations:

$$6\ H_2S + 3\ O_2 \equiv 2\ SO_2 + 4\ H_2S \quad \text{..... Equation 1}$$

$$4\ H_2S + 2\ SO_2 \equiv 6\ S + 4\ H_2O \quad \text{..... Equation 2}$$

The Claus process employs both thermal and catalytic reactors to accomplish the reactions shown in Equations 1 and 2 above with the ideal molar ratio of $H_2S:SO_2 = 2.0$. The reaction is carried out to completion in a thermal reactor and a series of catalytic reactors. About 60 percent of the feed sulfur is recovered in the thermal reactor and the rest is recovered in the catalytic reactors to give an overall sulfur recovery in the range of 95% to 96 % in the Claus units. The hot gases from the reaction furnace are cooled in a waste heat exchanger and in the sulfur condensers producing both 600 psig and 50 psig process steam for use in the refinery. The sulfur vapor is removed by condensation providing reactant equilibrium that favors furthering the reaction to the right and producing more sulfur in the catalytic converter stages that follow.

The remaining sulfur in the tail gas is fed to the SCOT units[7]. The Claus tail gas essentially consists of H_2S, SO_2 Carbonyl sulfide (COS), Carbon disulfide (CS_2) and trace amounts of elemental sulfur. All of these sulfur forms are reduced to H_2S in the presence of hydrogen. The H_2S is then selectively absorbed in Methyl diethanol amine (MDEA) solvent, which in turn is stripped. The stripped H_2S is recycled to the Claus Units and the SCOT tail gases are incinerated where trace H_2S is oxidized to SO_2 in a waste gas incinerator prior to discharge to the atmosphere. The condensed sulfur is collected in sulfur pits and transferred to holding tanks from where it is loaded into railcars and shipped off site.

K. Steam Methane Reformer Hydrogen Plant - Unit 37:

The 40 mmSCFD hydrogen plant[8] built in 1972 includes a pre-treatment carbon drum, reformer furnace 37-H-1, high and low temperature shift reactors, CO_2 stripper, methanation unit and hydrogen gas recovery compressor. Hydrogen (H_2) is an essential reactant in the hydrocracking process. While some of the refinery's H_2 requirement is supplied by the continuous catalyst regeneration (CCR) reformer, the balance of the H_2 is produced in this unit. This is accomplished by reforming steam in

[7] Tailgases from the SRUs are processed as follows: SRU I ≡ SCOT II and SRU II ≡ SCOT I

[8] The hydrogen plant also includes a 17,000 barrels per day hydrocracker unit (Unit 36) which was included as an emission unit in Title V **Permit: AQM-003/00016 - Part 1** dated Nov. 14, 2001.

the presence of a nickel catalyst heated to 1,500 EF in a tubular reformer heater (37-H-1) with a rated heat input of 439 mmBtu/hour on a 365 day rolling average. This unit has two furnace cells (north and south). The feed hydrocarbon which is a mixture of natural gas and coker gas is reformed to H_2 and carbon monoxide (CO) when reacted with steam. The CO formed further reacts with steam to form CO_2 in two water gas shift reactors, i.e., the high temperature and low temperature shift reactors (37-R-3 and 37-R-5). The general equations for these chemical reactions are as follows:

$C_nH_m + (n)\ H_2O \equiv (n + m/2)\ H_2 + (n)\ CO;$
$)H = 97{,}400$ Btu/lb[9]

$CO + H_2O \equiv H_2 + CO_2$
$)H = -\ 16{,}500$ Btu/lb[10] (water gas shift reaction)

The CO and CO_2 are removed by wet scrubbing the produced gas with a potassium carbonate solution which is then steam stripped in 37-C-1 and 37-C-2. Stripped CO_2 can either be emitted to the atmosphere or be sold to Air Liquide. A final methanation stage removes CO as follows:

$CO + 3\ H_2 \equiv CH_4 + H_2O$

$CO + 4\ H_2 \equiv CH_4 + 2\ H_2O$

Additionally, methanol is synthesized as a byproduct of the shift reaction in the two shift reactors (a high temperature shift (HTS) followed by a low temperature shift (LTS)) as follows:

$3\ H_2 + CO_2 + \text{catalyst} \equiv CH_3OH + H_2O + \text{heat}$

This CH_3OH is released to the atmosphere through the deaerator vent and/or the CO_2 vent located in the CO_2 removal process area. Catalyst vendor computer simulation results show that for conventional LTS catalyst approximately 90 % of the CH_3OH is formed in the LTS and 10 % in the HTS reactor. The byproduct CH_3OH formed in the LTS is highly dependent on the catalyst activity with catalyst activity decreasing with catalyst age. To minimize methanol emissions, a catalyst that slows down the rate of synthesis of CH_3OH is used in the LTS reactor.

L. **Reserved**[11]:

M. **Continuous Catalyst Regenerator (CCR) Reformer - Unit 42**:

The 10 million barrels per year CCR Reformer was built in 1983 and includes a reformer furnace 42-H-1,2,3, hydrogen purification - pressure swing adsorption (PSA) system, depropanizer, propanizer, heater 42-H-7, light straight run splitter, sulfur guard reactor and ancillary equipment. The primary purpose of the CCR is to reform light straight run (LSR) gasoline by increasing the aromatics content and thereby enhance the octane rating of the product. Charge from all CHU trains can be feedstock to the CCR. LSR feed to Unit 42 contains C_6 through C_{11} paraffins, naphthenes and aromatics. While, aromatics in the feed basically pass through unaffected, the naphthenes are highly selective to aromatic compounds and react relatively easily in the presence of a platinum catalyst. The paraffins in the feed are the most difficult to convert and the relative severity of the reforming process is determined by the

[9] Perry's Chemical Engineer's Handbook, Sixth Edition
[10] Perry's Chemical Engineer's Handbook, Sixth Edition
[11] The methanol plant has been permanently shut down.

level of paraffin conversion that is required.[12] Conversion is achieved in four basic reactions involving the following processes: dehydrogenation of naphthenes, isomerization of paraffins and naphthenes, dehydrocyclization of paraffins and hydrocracking of paraffins. Examples of these reactions are as follows:[13]

$C_7H_{14} \Omega C_7H_8 + 3\ H_2$ - dehydrogenation of methylcyclohexane to toluene
$C_6H_{14} \Omega C_6H_{14}$ - isomerization of n-hexane to 2,2 dimethylbutane
$C_7H_{16} \Omega C_7H_8 + H_2$ - dehydrocyclization of n-heptane to toluene, and
$C_7H_{16} + H_2 \Omega C_3H_8 + C_4H_{10}$ - hydrocracking of n-heptane to propane and butane.

The reactions take place in three reactors in the presence of a platinum catalyst. The reactors are stacked one above the other to allow the catalyst to move slowly down by gravity before exiting the last reactor section and going to the regeneration section. In the regeneration process, coke is burnt off the catalyst which is lifted back to the top of the first reactor. Because the reactions are endothermic heat has to be supplied. Charge to the unit is preheated in a feed effluent heat exchanger and fed to the first cell of the heater, i.e., 42-H-1 from where it enters the first reactor. Effluent from the first reactor is reheated in 42-H-2 and the effluent from the second reactor is reheated in 42-H-3 before being fed to the separator. Separator overhead is routed to the PSA for hydrogen removal and bottoms are taken to the depropanizer column where high octane product is extracted and used as feedstock to Unit 25. Catalyst in the CCR Reformer is regenerated continuously. This process involves reactivation of the catalyst by injection of a chloride ion. The catalyst regeneration involves a controlled burn process where the oxygen concentration is controlled to about 1 percent. Hydrochloric acid is formed as a result of the regeneration. The amount of HCl emitted depends on the degree of reactivation required by the catalyst. HCl emissions are controlled by a scrubber.

N. **Refinery Utilities, North & South Flares and Gas Recovery System, Spent Caustic Stripper - Unit 45**:

Refinery utilities are comprised of the following units: gas recovery and blowdown system, and the spent caustic stripper. The flare system was constructed in 1956and the spent caustic stripper constructed in 1995.

The refinery blowdown system is designed to safely conduct and dispose flammable vapors and gases discharged from venting and emergency relief operations. Two steam assisted flares are used for this purpose. The primary flare is the North flare located at the north end of the refinery near the power plant. The secondary flare is the South flare located at the south west corner of the plant. The blowdown system includes a blowdown drum and quench drum at each unit operation, a relief header running the length of the process units, a cooling water effluent vent header and a flare gas recovery system. With only the primary flare (North) operating, the refinery flare system is designed to handle about 800,000 lb/hour of gases at 200 deg. When the flow increases, such as during conditions of upset operations, the system can handle up to 1,500,000 lb/hour with both flares operating. The flare gas recovery system consists of two compressors each with a design capacity of 3.75 mmSCF/day. Of these two compressors, the Nash liquid ring compressor (K-3) serves as the primary recovery compressor. The standby compressor (K-1) is a reciprocating compressor that usually runs on a recycle mode. However, during the inspection the K-1 was on load and the K-3 was operating in the recycle mode. The recovery compressors are designed to recover all flows vented to the flare header unless the flare header pressure exceeds 19 inches water column. Both north and south flares are equipped with

[12] Robert A. Meyers, Handbook of Petroleum Refining Processes, Chapter 4.1 - UOP Platforming Process (Page 4.1 - 4.26), McGraw Hill, Second Edition, New York, 1996.
[13] Donald M. Little; Catalytic Reforming; Pennwell Pubishing Company, Oklahoma, 1985.

level controllers to maintain the water seal in their respective drums. Venting through either the north or south flares (or both) occurs only when the recovery compressors are overwhelmed.

The spent caustic stripper is a unit operation where malodorous caustic streams produced by several Merox sweetening processes in the refinery. These streams include Merox spent caustic from the FCCU, crude unit, alkylation unit, polymerization unit and the ether plant. The stripper uses CO_2 as a reagent that liberates H_2S, mercaptans and phenols when it contacts the spent caustic in a packed bed. Residual mercaptans and phenols are then removed by liquid extraction of the spent caustic with coker gasoline. Treatment in the stripper reduces the potential for odors emanating from the spent caustic.

O. **Facility Wide Requirements**:

The facility wide requirements include requirements for fugitive emissions from equipment leaks. Also included in this section are the insignificant activities.

Applicable Requirements, Technical/Regulatory Review and Compliance Determination Methodology:

Applicable Regulation/Permit	Technical/Regulatory Description	Title V Permit Condition	Compliance Methodology
Emission Unit 10: AA. WWTP – Oily Sewer System			
Regulation No. 2	Permits **APC-93/0350-C/O** dated June 25, 2001	Condition 3, Table 1, Section aa	Compliance with the emission standards and operational limitations are based on the monitoring and testing requirements. The monitoring and testing requirements define the change out schedule for the carbon adsorbers.
Regulation No. 14	Visible Emissions	Condition 3, Table 1, Condition ob.1	Compliance with the VE requirements for the oily water sewer is a facility wide requirement to conduct weekly qualitative observations to determine the presence of any visible emissions. If visible emissions are observed the Company shall take corrective action and/or determine compliance by conducting VE evaluations in accordance with RM 9 in 40 CFR 60, Appendix A.
Regulation No. 19	Control of Odorous Air Contaminants	Condition 3, Table 1, Condition ob.2	Compliance with the emission standard shall be demonstrated in accordance with the monitoring/testing and recordkeeping requirements. Monitoring/testing includes scentometer tests, air quality monitoring data and affidavits from affected citizens
Regulation No. 20, § 11 Regulation 24, Section 28 40 CFR Part 60, Subpart QQQ 40 CFR Part 61, Subpart FF and Part 63, Subpart CC	NSPS for VOC Emissions from Refinery WWTP Control of Volatile Organic Compounds NSPS for VOC Emissions from Refinery WWTP NESHAP and MACT standards for Petroleum Refineries	Condition 3, table 1, Conditions aa.1i, and aa.1.ii	Compliance with the emission standards and operational limitations shall be demonstrated in accordance with the monitoring/testing and recordkeeping requirements. The monitoring and testing requirements define the change out schedule for the carbon adsorbers.
Emission Unit 10: AB. WWTP – API/CPI Separators, and Tanks for Spill Diversion, Equalization, Flocculation and Flash Mixing			

Applicable Regulation/Permit	Technical/Regulatory Description	Title V Permit Condition	Compliance Methodology
Regulation No. 2	Permits **APC-81/1008-C/O (A4)(*NESHAP*)** dated Feb. 22, 2001 **APC-81/1009-C/O (A2)(*NESHAP*)** dated Nov. 8, 1999	Condition 3, Table 1, Section ab	Compliance with the emission standards shall be based on the monitoring requirements in Attachment 1 to this permit Compliance with the equipment standards and operational limitations are based on the monitoring and testing requirements. The monitoring and testing requirements prescribe the frequency and type of inspections to assess compliance
Regulation No. 20, § 11 Regulation 24, Section 28 40 CFR Part 60, Subpart QQQ 40 CFR Part 61, Subpart FF and Part 63, Subpart CC	NSPS for VOC Emissions from Refinery WWTP Control of Volatile Organic Compounds NSPS for VOC Emissions from Refinery WWTP NESHAP and MACT standards for Petroleum Refineries	Condition 3, table 1, Conditions ab.1i, ab.1.ii and ab.1.iii	Compliance with the emission standards, equipment standards and operational limitations shall be demonstrated in accordance with the monitoring/testing and recordkeeping requirements. The monitoring and testing requirements prescribe the frequency and type of inspections to assess compliance.
Emission Unit 10: AC. WWTP – DNF System, ORS, and VCU			
Regulation No. 2	Permits **APC-94/0710-O (*NESHAP)(*NO_x *RACT)*)** dated Apr. 14, 1998	Condition 3, Table 1, Section ac	Compliance with the emission standards shall be based on the following: For PM, SO_2:and NO_x Fuel usage and quality For VOC: The monitoring and testing requirements The Company shall monitor the fuel usage and firebox temperature
Regulation No. 4	Particulate Emissions From Fuel Burning Equipment	Condition 3, Table 1, Condition ac.1.	Compliance with the requirement of Regulation No. 4 shall be based on the fuel usage and quality
Regulation No. 8	SO_2 Emissions From Fuel Burning Equipment	Condition 3, Table 1, Condition ac.2.	Compliance with the requirement of Regulation No. 8 shall be based on the fuel usage and quality
Regulation No. 12	Control of NO_x Emissions	Condition 3, Table 1, Condition ac.3.	Compliance with the requirement of Regulation No. 12 shall be based on the fuel usage
Regulation No. 20, § 11 Regulation 24, Section 28 40 CFR Part 60, Subpart QQQ	NSPS for VOC Emissions from Refinery WWTP Control of Volatile Organic Compounds NSPS for VOC Emissions from Refinery	Condition 3, table 1, Conditions ac.4.i, ac.4.ii and ac.4.iii	Compliance with the emission standards, equipment standards and operational limitations shall be demonstrated in accordance with the monitoring/testing and recordkeeping requirements.

Applicable Regulation/Permit	Technical/Regulatory Description	Title V Permit Condition	Compliance Methodology
40 CFR Part 61, Subpart FF and Part 63, Subpart CC	WWTP NESHAP and MACT standards for Petroleum Refineries		The monitoring and testing requirements prescribe the frequency and type of inspections to assess compliance.
Regulation No. 14	Visible Emissions	Condition 3, Table 1, Condition ac.5.i	Compliance with the requirement of Regulation No. 14 shall be based on daily qualitative stack observations to determine the presence of any visible emissions. If visible emissions are observed the Company shall take corrective action and/or determine compliance by conducting VE evaluations in accordance with RM 9 in 40 CFR 60, Appendix A.
Emission Unit 10: AD. Gasoline Dispensing Facility			
Regulation 2	Permits **APC-95/0862-OI** dated Apr. 28, 1995 **APC-95/0863-OII** dated Apr. 28, 1995	Condition 3, Table 1, Section ad	Compliance with the emission standards and operational limitations are based on the monitoring and testing requirements. The monitoring and testing requirements define the periodic testing requirements for the gasoline dispensing facility
Regulation 24, Sections 26 and 36	Control of Volatile Organic Compounds	Condition 3, table 1, Conditions ad.1.i, and ad.1.ii	Compliance with the emission standards, equipment standards and operational limitations shall be demonstrated in accordance with the monitoring/testing and recordkeeping requirements. The monitoring and testing requirements prescribe the frequency and type of inspections to assess compliance.
Emission Unit 15: B. MVR			
Regulation No. 2	Permits **APC-954/0471-O (A2)(*MACT)(RACT)*** dated May 3, 2002	Condition 3, Table 1, Section b	Compliance with the emission standards shall be based on the following: For PM and SO_2: Fuel usage and quality For NO_x and CO: The monitoring and testing requirements The Company shall conduct a Department approved stack test at 5 year intervals

Applicable Regulation/Permit	Technical/Regulatory Description	Title V Permit Condition	Compliance Methodology
			For VOC: Operating the VCU in accordance with 40 CFR 60.18, complying with the operational limitations, operating a calibrated heat sensing device and on the monitoring/testing requirements. The monitoring and testing requirements prescribe monitoring the maximum hourly loading rate and operating and maintaining a heat sensing device during all loading cycles.
Regulation No. 4	Particulate Emissions From Fuel Burning Equipment	Condition 3, Table 1, Condition b.2.i	Compliance with the requirement of Regulation No. 4 shall be based on the fuel usage and quality
Regulation No. 8	SO_2 Emissions From Fuel Burning Equipment	Condition 3, Table 1, Condition b.3.i	Compliance with the requirement of Regulation No. 8 shall be based on the fuel usage and quality
Regulation No. 12	Control of NO_x Emissions	Condition 3, Table 1, Condition b.4.i	Compliance with the requirement of Regulation No. 12 shall be based on the fuel usage and the periodic stack testing requirement
Regulation No. 20, § 11 Regulation 24, Section 28, 29 And 43 40 CFR Part 63, Subparts Y and CC	NSPS for VOC Emissions from Refinery WWTP Control of Volatile Organic Compounds NESHAP/MACT standards for Marine Vessel Loading Operations and for Petroleum Refineries	Condition 3, table 1, Conditions b.6.i and b.6.ii	Compliance with the regulatory requirements shall be based on operating the VCU in accordance with 40 CFR 60.18, complying with the operational limitations, operating a calibrated heat sensing device and on the monitoring/testing requirements. The monitoring and testing requirements prescribe monitoring the maximum hourly loading rate and operating and maintaining a heat sensing device during all loading cycles.
Regulation No. 14	Visible Emissions	Condition 3, Table 1, Condition b.7.i	Compliance with the requirement of Regulation No. 14 shall be based on daily qualitative stack observations to determine the presence of any visible emissions. If visible emissions are observed the Company shall take corrective action and/or determine compliance by conducting VE evaluations in accordance with RM 9 in 40 CFR 60, Appendix A.
Emission Unit 21:			

Applicable Regulation/Permit	Technical/Regulatory Description	Title V Permit Condition	Compliance Methodology
	C. CU, CU Atmospheric Tower Heater, 21-H-701 and CU Vacuum Tower Heater, 21-H-2		
Regulation No. 2	Permits **APC-2004/0828-O(A1)(*MACT)(RACT)*** dated June 29, 2007 **APC-95/0570O(A2)(*LAER)(NSPS)*** dated June 29, 2007	Condition 3, Table 1, Section c	Compliance with the operational limitations for crude unit fresh feed throughput and process heaters heat input restrictions are based on the monitoring and testing requirements. The monitoring and testing requirements require monitoring the daily fresh feed throughput to the crude unit, obtaining the fuel heating value from daily fuel samples for the fuel fired in 21-H-701 and 21-H-2 and monitoring the daily fuel usage. Compliance with the emission standards and operational limitations for the 2 process heaters are based on the following: For PM, VOC and CO: Periodic stack test based emission factor and fuel usage For SO_2: Fuel usage and quality and compliance with the monitoring requirements for the approved AMP For NO_x: CEMS The monitoring and testing requirements prescribe periodic stack tests for PM, VOC and CO at 5 year intervals.
Regulation No. 4	Particulate Emissions From Fuel Burning Equipment	Condition 3, Table 1, Condition c.2.i	Compliance with the requirement of Regulation No. 4 shall be based on stack test based emission factor and the fuel usage and quality
Regulation No. 8	SO_2 Emissions From Fuel Burning Equipment	Condition 3, Table 1, Condition c.3.i	Compliance with the requirement of Regulation No. 8 shall be based on the fuel usage and quality
Regulation No. 12	Control of NO_x Emissions	Condition 3, Table 1, Condition c.4.i	Compliance with the requirement of Regulation No. 12 shall be based on CEMS
Regulation No. 14	Visible Emissions	Condition 3, Table 1, Condition c.7.i	Compliance with the requirement of Regulation No. 14 shall be based on daily qualitative stack observations to determine the presence of any visible emissions. If visible emissions are observed the Company shall take corrective action and/or

Applicable Regulation/Permit	Technical/Regulatory Description	Title V Permit Condition	Compliance Methodology
			determine compliance by conducting VE evaluations in accordance with RM 9 in 40 CFR 60, Appendix A.
Regulation No. 20, § 11 and 40 CFR Part 60, Subpart J	NSPS for Petroleum Refineries	Condition 3, table 1, Conditions c.2.i and c.2.ii	Compliance with the regulatory requirements shall be based on combusting only desulfurized RFG in 21-H-701 and 21-H-2. Additionally, process vent gas from the Merox oxidizer column 21-C-104 shall be sampled and tested in accordance with the approved AMP.
Regulation No. 24, §s 28 & 29 40 CFR 60, Subpart GGG 40 CFR Part 63, Subpart CC	Control of Volatile Organic Compounds NSPS for Petroleum Refineries NESHAP/MACT standards for Petroleum Refineries	Condition 3, table 1, Conditions c.6.i	Compliance with the NSPS and MACT requirements shall be based on the test methods and procedures in 40 CFR 60.592 and on 40 CFR 63.648 as applicable. Compliance with the operational limitations shall be based on piping uncondensed vapors to a firebox or incinerator. Alternately these vapors may be compressed and added to RFG. During process units turnarounds compliance shall be based on depressurization venting to a vapor recovery system, flare or firebox and by monitoring the pressure in each process or vessel until its internal pressure is 136 kPa or less.
Regulation No. 25, § 2	Preconstruction Requirements (NSR)	Condition 3, table 1, Conditions c.4.i	Compliance with the requirement of Regulation No. 25 shall be based on CEMS
Regulation No. 39	NO_x Budget Trading Program	Condition 3, Table 1, Condition da.4.i.B	Compliance with the emission standards are based on the monitoring, testing and recordkeeping requirements. Monitoring is based on CEMS.
Emission Unit 22: DA. FCU, FCU COB and SNCR, FCU WGS and Back Up Incinerator			
Regulation No. 2	Permits **APC-81/0829-O(A6)** dated June 29, 2007	Condition 3, Table 1, Section da	Compliance with the operational limitations for the FCU throughput, the requirement to combust only desulfurized fuel gas in fuel gas combustion devices and the requirements for the proper operation of the APCDs during all times when the FCU is operating are based on the monitoring, testing and

Applicable Regulation/Permit	Technical/Regulatory Description	Title V Permit Condition	Compliance Methodology
			recordkeeping requirements. The monitoring and testing requirements require monitoring the H_2S content in RFG, the daily fresh feed throughput to the FCU and the calculated coke burn rates. Compliance with the emission standards are based on the following: For PM, H_2SO_4, and Pb: Periodic stack tests at 3-year intervals unless the Department approves less frequent testing. For SO_2, NO_x and CO: CEMS For HAPs: Periodic stack test based emission factor and coke burn rate. Additionally, the permit prescribes operational limitations during periods of planned and unplanned start ups and shut downs. Compliance with these requirements for planned and unplanned start ups and shut downs shall be based on compliance with the requirements in Attachment XX of this permit, including information available to the Department concerning the company's actions with respect to such events, and shall include the Department's review of all available facts and circumstances including, but not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.
Regulation No. 5	Particulate Emissions From Industrial Process Operations	Condition 3, Table 1, Conditions da.2.i and da.2.ii	Compliance with the requirement of Regulation No. 5 shall be based on compliance with the NSPS limit of 0.1 grain H_2S/dscf of RFG and the monitoring/testing requirements. Additionally, compliance for PM emissions from the back up

Applicable Regulation/Permit	Technical/Regulatory Description	Title V Permit Condition	Compliance Methodology
			incinerator shall be based on maintaining a minimum operating temperature of 1,700ºF, minimum residence time of 2.0 sec and minimum excess O_2 level of 1.9 %. The monitoring/testing requirements prescribe annual stack tests for TSP, PM_{10} and H_2SO_4 unless the Department approves less frequent testing.
Regulation No. 8	SO_2 Emissions From Fuel Burning Equipment	Condition 3, Table 1, Condition da.3.i	Compliance is based on CEMS
Regulation No. 11	CO Emissions From Industrial Process Operations	Condition 3, Table 1, Condition da.5.i	Compliance is based on CEMS
Regulation No. 14	Visible Emissions	Condition 3, Table 1, Condition da.11.i	For units 22-H-2 and 22-H-4: Compliance with the requirement of Regulation No. 14 shall be based on daily qualitative stack observations to determine the presence of any visible emissions. If visible emissions are observed the Company shall take corrective action and/or determine compliance by conducting VE evaluations in accordance with RM 9 in 40 CFR 60, Appendix A. For Units 22-H-1 and 22-H-3: Compliance shall be based on the monitoring and testing requirements in the approved AMP.
Regulation No. 24, §s 28 & 29 40 CFR 60, Subpart GGG 40 CFR Part 63, Subpart CC	Control of Volatile Organic Compounds NSPS for Petroleum Refineries NESHAP/MACT standards for Petroleum Refineries	Condition 3, Table 1, Conditions da.6.i	Compliance with the NSPS and MACT requirements shall be based on the test methods and procedures in 40 CFR 60.592 and on 40 CFR 63.648 as applicable. Compliance with the operational limitations shall be based on piping uncondensed vapors to a firebox or incinerator. Alternately these vapors may be compressed and added to RFG. During process units turnarounds compliance shall be based on depressurization venting to a vapor recovery system, flare or firebox and by monitoring the pressure in each process or vessel until its internal pressure is 136 kPa

Applicable Regulation/Permit	Technical/Regulatory Description	Title V Permit Condition	Compliance Methodology
			or less.
Regulation No. 39	NO_x Budget Trading Program	Condition 3, Table 1, Condition da.4.i.B	Compliance with the emission standards are based on the monitoring, testing and recordkeeping requirements. Monitoring is based on CEMS.
Emission Unit 22: DB. Fluid Coke Handling and Storage Facility			
Regulation No. 2	Permits **APC-82/1209-O(A3)** dated May 2, 2005	Condition 3, Table 1, Section db	Compliance with the emission standards are based on the calculations using the same methodology and equations used in the permit application, and on the monitoring requirements for the pressure drop across the baghouse filter. Compliance with the operational limitations are based on the sampling and monitoring requirements. The monitoring requirements prescribe the coke sampling requirements to determine the moisture content of the coke destined for truck shipments
Regulation No. 14	Visible Emissions	Condition 3, Table 1, Condition db.2.i	Compliance with the requirement of Regulation No. 14 shall be based on daily qualitative stack observations to determine the presence of any visible emissions. If visible emissions are observed the Company shall take corrective action and/or determine compliance by conducting VE evaluations in accordance with RM 9 in 40 CFR 60, Appendix A.
Emission Unit 23: E. FCCU, FCCU COB and FCU WGS			
Regulation No. 2	Permits **APC-82/0981-O(A6)Addendum 1** dated September 27, 2007	Condition 3, Table 1, Section e	Compliance with the operational limitations for the requirement to combust only desulfurized fuel gas in fuel gas combustion devices and the requirements for the proper operation of the APCDs during all times when the FCCU is operating are based on the monitoring, testing and recordkeeping requirements. The monitoring and testing requirements require

Applicable Regulation/Permit	Technical/Regulatory Description	Title V Permit Condition	Compliance Methodology
			monitoring the H_2S content in RFG and the calculated coke burn rates. Compliance with the emission standards are based on the following: For PM, H_2SO_4, and Pb: Periodic stack tests at 3-year intervals unless the Department approves less frequent testing. For SO_2, NO_x and CO: CEMS For HAPs: Periodic stack test based emission factor and coke burn rate. Additionally, the permit prescribes operational limitations during periods of planned and unplanned start ups and shut downs. Compliance with these requirements for planned and unplanned start ups and shut downs shall be based on compliance with the requirements in Attachment XX of this permit, including information available to the Department concerning the company's actions with respect to such events, and shall include the Department's review of all available facts and circumstances including, but not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source.
Regulation No. 5	Particulate Emissions From Industrial Process Operations	Condition 3, Table 1, Conditions e.2.i	Compliance with the requirement of Regulation No. 5 shall be based on compliance with the NSPS limit of 0.1 grain H_2S/dscf of RFG and the monitoring/testing requirements. Additionally, compliance for PM emissions from the back up incinerator shall be based on maintaining a minimum operating temperature of 1,700ºF, minimum

Applicable Regulation/Permit	Technical/Regulatory Description	Title V Permit Condition	Compliance Methodology
			residence time of 2.0 sec and minimum excess O_2 level of 1.9 %. The monitoring/testing requirements prescribe annual stack tests for TSP, PM_{10} and H_2SO_4 unless the Department approves less frequent testing.
Regulation No. 8	SO_2 Emissions From Fuel Burning Equipment	Condition 3, Table 1, Condition e.3.i	Compliance is based on CEMS
Regulation No. 11	CO Emissions From Industrial Process Operations	Condition 3, Table 1, Condition e.5.i	Compliance is based on CEMS
Regulation No. 14	Visible Emissions	Condition 3, Table 1, Condition e.10.i	For units 22-H-2 and 22-H-4: Compliance with the requirement of Regulation No. 14 shall be based on daily qualitative stack observations to determine the presence of any visible emissions. If visible emissions are observed the Company shall take corrective action and/or determine compliance by conducting VE evaluations in accordance with RM 9 in 40 CFR 60, Appendix A. For Units 22-H-1 and 22-H-3: Compliance shall be based on the monitoring and testing requirements in the approved AMP.
Regulation No. 20, § 11 and 40 CFR Part 60, Subpart J	NSPS for Petroleum Refineries	Condition 3, table 1, Conditions e.1.i.F, e.5.i and e.10.i	Compliance with the regulatory requirements shall be based on combusting only desulfurized RFG in 23-H-3. Additionally, spent air from 24-C-10 (Alky Merox), spent air from 26-C-5 (Poly Merox) and process vent gas from the FCCU Regenerator may be combusted in 23-H-3.
Regulation No. 24, §s 28 & 29 40 CFR 60, Subpart GGG 40 CFR Part 63, Subparts CC and UUU	Control of Volatile Organic Compounds NSPS for Petroleum Refineries NESHAP/MACT standards for Petroleum Refineries	Condition 3, Table 1, Conditions e.6.i	Compliance with the NSPS and MACT requirements shall be based on the test methods and procedures in 40 CFR 60.592 and on 40 CFR 63.648 as applicable. Compliance with the operational limitations shall be based on piping uncondensed vapors to a firebox or incinerator. Alternately these vapors may be compressed and added to RFG. During process units

Applicable Regulation/Permit	Technical/Regulatory Description	Title V Permit Condition	Compliance Methodology
			turnarounds compliance shall be based on depressurization venting to a vapor recovery system, flare or firebox and by monitoring the pressure in each process or vessel until its internal pressure is 136 kPa or less.
Regulation No. 39	NO_x Budget Trading Program	Condition 3, Table 1, Condition e.4.i.A	Compliance with the emission standards are based on the monitoring, testing and recordkeeping requirements. Monitoring is based on CEMS.
Emission Unit 24: F. Refinery Gas Plant (No emission points, i.e. only fugitive emissions that are covered under Section O – Facility Wide Requirements)			
Emission Unit 25: G. Reformer & RFG 2K, CNHT Unit, Butamer Unit and Cooling Tower			
Regulation No. 2	Permits **APC-98/0522-O*(RACT)(NSPS)*** dated June 18., 2002 **APC-98/0523-O(*NSPS)(RACT)(NESHAP)*** dated March 11, 2002	Condition 3, Table 1, Section g	Compliance with the operational limitations for the process heaters' heat input restrictions are based on the monitoring and testing requirements. The monitoring and testing requirements require monitoring the fuel gas usage and obtaining the fuel heating value from daily fuel samples for the fuel fired in 25-H-401 and 25-H-402. Compliance with the emission standards and operational limitations for the 2 process heaters are based on the following: For PM, VOC and CO: On the fuel usage and quality. For SO_2: Fuel usage and the rolling 12 month average sulfur content of the fuel as determined using H_2S CEMS For NO_x: Annual stack test
Regulation No. 4	Particulate Emissions From Fuel Burning Equipment	Condition 3, Table 1, Condition g.2.i.B	Compliance with the requirement of Regulation No. 4 shall be based on compliance with the emission standard in Condition g.2.1.A.3
Regulation No. 5	Particulate Emissions From Industrial Process Operations	Condition 3, Table 1, Conditions	Compliance with the requirement of Regulation No. 5 shall be based on the proper operation of the high

Applicable Regulation/Permit	Technical/Regulatory Description	Title V Permit Condition	Compliance Methodology
		g.2.i.C	efficiency mist eliminator having a vendor guaranteed emission factor of 0.002 % drift loss per lb of cooling water circulated and on the monitoring requirements. The monitoring and testing requirements require monitoring the cooling water flow rate and conduct a quarterly test of total solids using Method 2540B of Standard Method for the Examination of Water and Wastewater.
Regulation No. 8	SO_2 Emissions From Fuel Burning Equipment	Condition 3, Table 1, Condition g.3.i	Compliance with the requirement of Regulation No. 8 shall be based on compliance with Emission Standard g.1.E.
Regulation No. 12	Control of NO_x Emissions	Condition 3, Table 1, Condition g.4.i.C	Compliance with the requirement of Regulation No. 12 shall be based on an annual stack test.
Regulation No. 14	Visible Emissions	Condition 3, Table 1, Condition g.7.i	Compliance with the requirement of Regulation No. 14 shall be based on daily qualitative stack observations to determine the presence of any visible emissions. If visible emissions are observed the Company shall take corrective action and/or determine compliance by conducting VE evaluations in accordance with RM 9 in 40 CFR 60, Appendix A.
Regulation No. 20, § 11 and 40 CFR Part 60, Subpart J	NSPS for Petroleum Refineries	Condition 3, Table 1, Condition g.1.i.F	Compliance with the regulatory requirements shall be based on combusting only desulfurized RFG and/or natural gas in 25-H-401 and 25-H-402
Emission Unit 26: H. Polymerization Unit (No emission points, i.e. only fugitive emissions that are covered under Section O – Facility Wide Requirements)			
Emission Unit 27: I. Alkylation Unit (No emission points, i.e. only fugitive emissions that are covered under Section O – Facility Wide Requirements)			
Emission Unit 28: J. SRA; Claus Units I and II, Sulfur Pits and SCOT Units I and II			
Regulation No. 2	Permits **APC-90/0264-O(A6)*(NSPS)*** dated June 29,	Condition 3, Table 1, Section j	Compliance with the operational limitations A, B, D, E and H shall be based on recordkeeping.

Applicable Regulation/Permit	Technical/Regulatory Description	Title V Permit Condition	Compliance Methodology
	2007		Compliance with operational limitation C shall be based on CEMS Compliance with operational limitation F is defined as maintaining a negative pressure in the sulfur pits on a minute basis Compliance with operational limitation G shall be based on information available to the Department concerning the Company's actions with respect to such events, and shall include the Department's review of all available facts and circumstances including but not limited to, monitoring results, opacity and process operating rate. The monitoring and recordkeeping requirements prescribe the requirements to monitor the sulfur pit pressure continuously and record the daily sulfur production. Compliance with the emission standards and operational limitations for both Claus trains and SCOT units I and II are based on the following: For PM, VOC and CO: On the fuel usage and the monitoring/testing requirements. For SO_2: Fuel usage and the rolling 12 month average sulfur content of the fuel as determined using H_2S CEMS For NO_x: Annual stack test
Regulation No. 4	Particulate Emissions From Fuel Burning Equipment	Condition 3, Table 1, Condition j.2.i.B	Compliance with the requirement of Regulation No. 4 shall be based on compliance with the emission standard in Condition g.2.1.A.3
Regulation No. 8	SO_2 Emissions From Fuel Burning Equipment	Condition 3, Table 1, Condition j.1.i.E	Compliance with the requirement of Regulation No. 8 shall be based on compliance with Emission Standard g.1.E.
Regulation No. 9	Emissions of Sulfur Compounds from Industrial operations	Condition 3, Table 1, Condition j.3.i.D	Compliance with the requirement of Regulation No. 8 shall be based on compliance with Emission

Applicable Regulation/Permit	Technical/Regulatory Description	Title V Permit Condition	Compliance Methodology
			Standard g.1.E.
Regulation No. 14	Visible Emissions	Condition 3, Table 1, Condition j.9.i	Compliance with the requirement of Regulation No. 14 shall be based on daily qualitative stack observations to determine the presence of any visible emissions. If visible emissions are observed the Company shall take corrective action and/or determine compliance by conducting VE evaluations in accordance with RM 9 in 40 CFR 60, Appendix A.
Regulation No. 20, § 11 and 40 CFR Part 60, Subpart J	NSPS for Petroleum Refineries	Condition 3, Table 1, Conditions j.1.i.C and j.3.i	Compliance with the regulatory requirements shall be based on combusting only desulfurized RFG and/or natural gas in SCOT units I & II. Compliance with the SO_2 emissions limitation shall be based on CEMS.
40 CFR Part 63, Subpart UUU	NESHAP/MACT standards for Petroleum Refineries	Condition 3, Table 1, Condition j.3.i	Compliance with the MACT standard in subpart UUU is based on compliance with the NSPS standard.
Emission Unit 37: K. SMRHP			
Regulation No. 2	Permits **APC-90/0965-O(A1)** dated June 29, 2007	Condition 3, Table 1, Section k	Compliance with the operational limitations and process heater heat input restrictions are based on the monitoring/testing and recordkeeping requirements. The monitoring/testing and recordkeeping requirements prescribe the requirements to monitor the fuel usage continuously, to determine the fuel heating value from daily sampling and testing of the fuel, and monitoring the fuel H_2S content continuously by CEMS.
Regulation No. 4	Particulate Emissions From Fuel Burning Equipment	Condition 3, Table 1, Condition k.2.i	Compliance with the requirement of Regulation No. 4 shall be based on compliance with the operational limitation in Condition k.1.i
Regulation No. 8	SO_2 Emissions From Fuel Burning Equipment	Condition 3, Table 1, Condition k.3.i	Compliance with the requirement of Regulation No. 8 shall be based on compliance with the operational limitation in Condition k.1.i

Applicable Regulation/Permit	Technical/Regulatory Description	Title V Permit Condition	Compliance Methodology
Regulation No. 12	Control of NO_x Emissions	Condition 3, Table 1, Condition k.4.i	Compliance with the requirement of Regulation No. 12 shall be based on CEMS
Regulation No. 14	Visible Emissions	Condition 3, Table 1, Condition k.6.i	Compliance with the requirement of Regulation No. 14 shall be based on daily qualitative stack observations to determine the presence of any visible emissions. If visible emissions are observed the Company shall take corrective action and/or determine compliance by conducting VE evaluations in accordance with RM 9 in 40 CFR 60, Appendix A.
Regulation No. 24, § 50	Control of Volatile Organic Compounds	Condition 3, table 1, Condition k.5.1	Compliance with the operational limitations shall be based on the monitoring/testing and recordkeeping requirements. The monitoring/testing requirements prescribe the stack test requirements within 60 days of replacement of the LTS catalyst, at the end of the first year and at 2 year intervals thereafter. The stack test results shall be used to quantify VOC emissions from the CO_2 and deaerator vents using the following equation: % VOC reduction = 100 [1 - (CO_2 vent rate)(1 - fraction of CO_2 to Air Liquide) + (Deaerator vent rate)] / Baseline CH_3OH where CO_2 and deaerator vent rates are stack test based VOC emission rates
Regulation No. 39	NO_x Budget Trading Program	Condition 3, Table 1, Condition k.4.i.B	Compliance with the emission standards are based on the monitoring, testing and recordkeeping requirements. Monitoring is based on CEMS.
L. RESERVED			
Emission Unit 42: M. CCR Reformer, CCR Reformer Charge Heater 42-H-1,2,3, and Reboiler Heater 42-H-7			
Regulation No. 2	Permits **APC-82/0073-O** dated February 8, 1985	Condition 3, Table 1, Section m	Compliance with the operational limitations and process heaters heat input restrictions are based on

Applicable Regulation/Permit	Technical/Regulatory Description	Title V Permit Condition	Compliance Methodology
	APC-82/0632-O dated February 8, 1985 **APC-82/0073-O(A1)*(MACT)*** dated August 16, 2005		the monitoring/testing and recordkeeping requirements. The monitoring/testing and recordkeeping requirements prescribe the requirements to monitor the fuel usage continuously, to determine the fuel heating value from daily sampling and testing of the fuel, and monitoring the fuel H_2S content continuously by CEMS.
Regulation No. 4	Particulate Emissions From Fuel Burning Equipment	Condition 3, Table 1, Condition m.2.i	Compliance with the requirement of Regulation No. 4 shall be based on compliance with the operational limitation in Condition m.1.i
Regulation No. 8	SO_2 Emissions From Fuel Burning Equipment	Condition 3, Table 1, Condition m.3.i	Compliance with the requirement of Regulation No. 8 shall be based on compliance with the operational limitation in Condition m.1.i
Regulation No. 12	Control of NO_x Emissions	Condition 3, Table 1, Condition m.4.i	Compliance with the requirement of Regulation No. 12 shall be based on CEMS
Regulation No. 14	Visible Emissions	Condition 3, Table 1, Condition m.5.i	Compliance with the requirement of Regulation No. 14 shall be based on daily qualitative stack observations to determine the presence of any visible emissions. If visible emissions are observed the Company shall take corrective action and/or determine compliance by conducting VE evaluations in accordance with RM 9 in 40 CFR 60, Appendix A.
Regulation No. 20, § 11 and 40 CFR Part 60, Subpart J	NSPS for Petroleum Refineries	Condition 3, Table 1, Conditions m.1.i.C and m.1.i.D	Compliance with the regulatory requirements shall be based on combusting only desulfurized RFG and/or natural gas in 42-0H-1,2,3 and 42-H-7. In addition, 42-H-1,2,3 may combust process vent gas from the reactor lift engager 42-D-11.
40 CFR Part 63, Subpart UUU	NESHAP/MACT standards for Petroleum Refineries	Condition 3, Table 1, Conditions m.6.i	Compliance with the MACT requirements shall be based on the monitoring/testing and recordkeeping requirements. The monitoring/testing and recordkeeping requirements prescribe the MACT requirements in Table 41 of 40 CFR 63, subpart UUU

Applicable Regulation/Permit	Technical/Regulatory Description	Title V Permit Condition	Compliance Methodology
Regulation No. 39	NO_x Budget Trading Program	Condition 3, Table 1, Condition m.4.i.B	Compliance with the emission standards are based on the monitoring, testing and recordkeeping requirements. Monitoring is based on CEMS.
N. Refinery Utilities, North and South FGR System, SCS			
Regulation No. 2	Permits **APC-81/0830-O** dated July 30, 1981 **APC-95/0381-O** dated May 13, 1996	Condition 3, Table 1, Conditions n.1.i and n.2.i	Compliance with the operational limitations of the flares are based on the monitoring/testing and recordkeeping requirements. The monitoring/testing and recordkeeping requirements prescribe the requirements to monitor the fuel usage continuously, to determine the fuel heating value from daily sampling and testing of the fuel, and monitoring the fuel H_2S content continuously by CEMS. Compliance with the operational limitations of the SCS are based on the monitoring/testing and recordkeeping requirements. The monitoring/testing and recordkeeping requirements prescribe the requirements to monitor and test samples of the spent caustic sulfide concentration daily using a Department approved method.
Regulation No. 20, § 11 and 40 CFR Part 60, Subpart J	NSPS for Petroleum Refineries	Condition 3, Table 1, Conditions n.1.i.C and n.1.i.D	Compliance with the regulatory requirements shall be based on combusting only desulfurized RFG and/or natural gas in the flare pilots.
O. Facility Wide Requirements			
Regulation No. 1, , § 3.2	Definitions and Administrative Principles	Condition 3 Table 1, Condition ob.6.i	Compliance with the operational limitations shall be based on whether acceptable operating procedures are being used, on information available to the Department which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures and inspection of the source.
Regulation No. 3	Ambient Air Quality Standards	Condition 2.b.7	
Regulation No. 14	Visible Emissions	Condition 3, Table 1, Condition ob.1.i	Compliance with the requirement of Regulation No. 14 shall be based on daily qualitative stack

Applicable Regulation/Permit	Technical/Regulatory Description	Title V Permit Condition	Compliance Methodology
			observations to determine the presence of any visible emissions. If visible emissions are observed the Company shall take corrective action and/or determine compliance by conducting VE evaluations in accordance with RM 9 in 40 CFR 60, Appendix A.
Regulation No. 17	Source Monitoring, Recordkeeping and Reporting	Condition 3.b	
Regulation No. 19	Control of Odorous Air Contaminants	Condition ob.2	This condition is state enforceable only and has been designated as such in the permit. Compliance shall be based on the monitoring/testing and recordkeeping requirements. The monitoring/testing requirements include, but is not limited to scentometer tests, air quality monitoring, and affidavits from cictizens and investigators.
Regulation No. 24, , § 8	Control of Volatile Organic Compounds – Handling, Storage and Disposal of VOCs	Condition 3, Table 1, Condition ob.3.i	Compliance shall be demonstrated by adherence with the VOC handling work practices by providing appropriate training and posting of instructions, and recordkeeping for storage, use and disposal of VOCs.
Regulation No. 24, , § 28	Control of Volatile Organic Compounds – Petroleum Refinery Sources	Condition 3, Table 1, Conditions ob.4.i	Compliance shall be demonstrated by adherence to the monitoring/testing and recordkeeping requirements. The monitoring requirements prior to turnarounds prescribe the requirement to monitor the internal pressure of each process unit and vessel immediately prior to venting to the atmosphere.
40 CFR 60, Subpart GGG 40 CFR 63, Subpart CC 40 CFR 60, Subpart VV Regulation 24, § 29	NESHAP/MACT standards for Petroleum Refineries NSPS for Petroleum Refineries Control of Volatile Organic Compounds-Leaks from Petroleum Refinery Equipment	Condition 3, Table 1, Conditions oa.1. through oa.13	These requirements prescribe the applicable LDAR requirements. Compliance with the HAP LDAR requirements for new equipment shall be in accordance with the requirements in 40 CFR 63, subpart H. Compliance with the HAP LDAR requirements for existing equipment shall be in accordance with the requirements in 40 CFR 63, subpart CC. Compliance with the requirements in

Applicable Regulation/Permit	Technical/Regulatory Description	Title V Permit Condition	Compliance Methodology
			Subpart CC are based on compliance with the NSPS requirements in 40 CFR 60, subpart VV. Compliance with the regulatory requirements of Regulation 24, § 29, are also based on compliance with the NSPS requirements in 40 CFR 60, subpart VV.

V. Future Applicable Requirements:

There are no future applicable requirements at this time.

VI. Compliance Schedule:

The most recent revision (i.e. Revision 9) of the permit application indicates two non-complying requirements

a. The MVR system at the refinery is subject to the reporting requirements in 40 CFR 63.567(j). This report has been submitted to DNREC as part of the annual emissions inventory. However, it has not been submitted to the EPA. The application indicates Premcor plans to submit this report to EPA by 01/30/2008.

b. Premcor is presently leasing 6 portable diesel driven air compressors with engine power rating greater than 450 hp for stand by duty operations. Two of these compressors provide reliable emergency back up supply air to the FCCU withdrawal well in the event refinery utility air supply is interrupted. Premcor plans to complete its reliability improvement to the refinery utility air system by 04/01/2008 and eliminate the 2 portable compressors at the FCCU. The remaining 4 compressors will continue to serve as stand by units and will be exempted under Regulation 30, Appendix "A", Section b.2.

Therefore, this permit does not contain a compliance schedule. *[Reference Regulation No. 30 Section 6(c)(3), dated 11/15/93].*

VII. Permit Shield:

Compliance with the terms and conditions of this permit shall be deemed compliance with the applicable requirements as provided in Condition 6—Table 1 as of the effective date of this permit. *[Reference Regulation No. 30 Section 6(f)(3), dated 11/15/93].*

Condition 6 – Table 1

Emission Unit	Applicable Requirement
1. Emission Unit 10	i. Regulation No. 2 ii. Regulation No. 3 iii. Regulation No. 4, Section 2.1 iv. Regulation No. 8, section 2.1 v. Regulation No. 12, Section 4.1 vi. Regulation No. 14, Section 2.1 vii. Regulation No. 20 viii. Regulation No. 24, Sections 1-10, 26, 28, 29 and 36 ix. 40 CFR Part 60, Subpart J x. 40 CFR Part 60, Subpart QQQ xi. 40 CFR Part 62, Subpart FF xii. 40 CFR Part 63, Subpart CC
2. Emission Unit 15	i. Regulation No. 2 ii. Regulation No. 3 iii. Regulation No. 4, Section 2.1 iv. Regulation No. 8, Section 2.1 v. Regulation No. 12 vi. Regulation No. 14, Section 2.1 vii. Regulation No. 17, Section 2.2 viii. Regulation No. 20 ix. Regulation No. 24, Section 1-10, 28, 29 and 43 x. 40 CFR Part 60, Subpart A xi. 40 CFR Part 60, Subpart J xii. 40 CFR Part 63, Subpart Y xiii. 40 CFR Part 63, Subpart CC
3. Emission Unit 21	i. Regulation No. 2 ii. Regulation No. 3 iii. Regulation No. 4, Section 2.1 iv. Regulation No. 8, Section 2.1 v. Regulation No. 9, Section 1.1 vi. Regulation No. 12 vii. Regulation No. 14, Section 2.1

	viii. Regulation No. 17, Section 2.3 ix. Regulation No. 20 x. Regulation No. 24, Section 1-10 and 29 xi. Regulation No. 25 xii. Regulation No. 39 xiii. 40 CFR Part 60, Subpart J xiv. 40 CFR Part 60, Subpart VV xv. 40 CFR Part 60, Appendix B xvi. 40 CFR Part 60, Appendix F xvii. 40 CFR Part 63, Subpart CC
4. Emission Unit 22	i. Regulation No. 2 ii. Regulation No. 3 iii. Regulation No. 4, Section 2.1 iv. Regulation No. 5 v. Regulation No. 8, Section 2.1 vi. Regulation No. 9, Section 1.1 vii. Regulation No. 11, Section 2.1 viii. Regulation No. 12, Section 3 ix. Regulation No. 14, Section 2.1 x. Regulation No. 17, Section 2.3 xi. Regulation No. 24, Section 1-10 and 29 xii. Regulation No. 39 xiii. 40 CFR Part 60, Subpart VV xiv. 40 CFR Part 60, Appendix B xv. 40 CFR Part 60, Appendix F xvi. 40 CFR Part 63, Subpart CC
5. Emission Unit 23	i. Regulation No. 2 ii. Regulation No. 3 iii. Regulation No. 4, Section 2.1 iv. Regulation No. 5 v. Regulation No. 8, Section 2.1 vi. Regulation No. 9, Section 1.1 vii. Regulation No. 11, Section 2.1 viii. Regulation No. 14, Section 2.1 ix. Regulation No. 17, Section 2.3 x. Regulation No. 20

	xi. Regulation No. 24, Sections 1-10 and 29 xii. Regulation No. 39 xiii. 40 CFR Part 60, Subpart VV xiv. 40 CFR Part 63, Subpart CC xv, 40 CFR Part 63, Subpart UUU
6. Emission Unit 24	i. Regulation No. 2 ii. Regulation No.3 iii. Regulation No. 20 iv. Regulation No. 24, Section 1-10 and 29 v. 40 CFR Part 60, Subpart J vi. 40 CFR Part 60, Subpart VV vii. 40 CFR Part 60, Appendix B viii. 40 CFR Part 60, Appendix F ix. 40 CFR Part 63, Subpart CC
7. Emission Unit 25	i. Regulation No. 2 ii. Regulation No. 3 iii. Regulation No. 4, Section 2.1 iv. Regulation No. 5, Section 2.1 v. Regulation No. 8, Section 2.1 vi. Regulation No. 12, Section 3 vii. Regulation No. 14, Section 2.1 viii. Regulation No. 17, Section 2.3 ix. Regulation No. 20 x. Regulation No. 24, Sections 1-10 and 29 xi. 40 CFR Part 60, Subpart J xii. 40 CFR Part 60, Subpart VV xiii. 40 CFR Part 60, Appendix B xiv. 40 CFR Part 60, Appendix F xv. 40 CFR Part 63, Subpart CC
8. Emission Unit 28	i. Regulation No. 2 ii. Regulation No. 3 iii. Regulation No. 4, Section 2.1 iv. Regulation No. 5 v. Regulation No. 8, Section 2.1 vi. Regulation No. 9, Section 3

	vii. Regulation No. 12 viii. Regulation No. 14, Section 2.1 ix. Regulation No. 17 x. Regulation No. 20 xi. Regulation No. 24, Sections 1-10 and 29 xii.40 CFR Part 60, Subpart J xiii. 40 CFR Part 60, Subpart VV xiv. 40 CFR Part 60, Appendix B xv. 40 CFR Part 60, Appendix F xvi. 40 CFR Part 63, Subpart CC xvii. 40 CFR Part 63, Subpart UUU
9. Emission Unit 37	i. Regulation No. 2 ii. Regulation No. 3 iii. Regulation No. 4, Section 2.1 iv. Regulation No. 8, Section 2.1 v. Regulation No. 12, Section 3 vi. Regulation No. 14, Section 2.1 vii. Regulation No. 17, Section 2.3 viii. Regulation No. 24, Sections 1-10, 29 and 50 ix. Regulation No. 39 x. 40 CFR Part 60, Subpart VV xi. 40 CFR Part 60, Appendix B xii. 40 CFR Part 60, Appendix F xiii. 40 CFR Part 60, Subpart CC
10. Emission Unit 42	i. Regulation No. 2 ii. Regulation No. 3 iii. Regulation No. 4, Section 2.1 iv. Regulation No. 8, Section 2.1 v. Regulation No. 12, Section 3 vi. Regulation No. 14, Section 2.1 vii. Regulation No. 17, Section 2.3 viii. Regulation No. 20 ix. Regulation No. 24, Section 1-10 and 29 x. Regulation No. 39

	xi. 40 CFR Part 60, Subpart J xii. 40 CFR Part 60, Subpart VV xiii. 40 CFR Part 60, Appendix B xiv. 40 CFR Part 60, Appendix F xv. 40 CFR Part 63, Subpart CC xvi. 40 CFR Part 63, Subpart UUU
11. Emission Unit 45	i. Regulation No. 2 ii. Regulation No. 3 iii. Regulation No.14, Section 2.1 iv. Regulation No. 17, Section 2.1 and 2.2 v. Regulation No. 24, Section 1-10 and 29 vi. 40 CFR Part 60, Subpart A vii. 40 CFR Part 60, Subpart VV
12. Emission Units 24, 26, 27 and Facility-wide	i. Regulation No. 3 ii. Regulation No. 14, Section 2.1 iii. Regulation No. 17, Section 2.2 and 7 iv. Regulation No. 19, Section 2.1 v. Regulation No. 24, Section 1-10, 9, 28, 29, 40 and 50 vi. 40 CFR Part 60, Subpart VV vii. 40 CFR Part 63, Subpart CC

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